RRSurvey_WhitepaperSupport_051905
Overall Results sorted by Survey Category and
Detailed Responses Sorted by Task Management Categories

Overall Survey Results – general conclusions

1. Production Cost/Pancaked Rates
   - Powerex Marketers, entities at fringe, new resources see rate pancakes as problematic.
   - Entities directly interconnected with BPA and customers located in BPA's control area have no problems.
   - Entities with surplus capacity/energy and/or no load growth don't see pancaking as a problem.
   - The effect of multiple wheeling fees (pancakes) is the prevention of otherwise efficient transactions that could lower production costs.
   - BPA's Regional Dialogue policy, which is expected to include a decision by BPA to fix the FBS, is expected to trigger more concerns with rate pancaking.
   - Administrative pancaking is perceived as a problem: purchasing timelines do not accommodate the trading market; there is a mismatch between providers' calculations of ATC which makes multiple system transactions very difficult; multiple and conflicting business practices; multiple and conflicting queuing procedures; multiple and conflicting Impact Study procedures.
   - Higher transaction costs and delays from queuing inconsistencies, multiple OASIS, inconsistent standards and rules, inconsistent approaches to tariff implementation, duplicative processes, etc.

2. Transmission System Operations
   - Some see the existing outage planning process as adequate.
   - Some see big problems with a lack of coordination at the seams and the lack of market considerations in setting outage schedules.
   - Some reported that the current process for identifying and settling area control errors is inefficient.
   - RAS is used where there are parallel paths in order to limit pre-schedule curtailments. RAS is increasingly more difficult to apply, especially in real-time and so, some are using dedicated RAS Operators and Automated Expert Systems to cope with the complexities.
   - Standards vary throughout the West as to how much RAS may be relied upon; it is not clear that the transmission provider knows in all cases when additional RAS may be acceptable.
   - Inability to redirect after curtailed and so forced to "take out" the schedule or "book out" the schedule with the generator.

- There are significant reliability problems from increasingly complex operations, transactions, and lack of a wide view of operating data and control.
- Control area consolidation which could come about with an independent operator would lead to significant efficiencies as a result of combining resource options of multiple control areas, and capturing load and system diversity, streamlining operations, improving reliability and facilitating emergency response.

3. System Capability and Scope
    - There are a number of examples for inconsistent determinations of TRM and CBM at seams, e.g., the BC/Alberta border and BC/US border, the Pacific Intertie, control area interfaces. .
    - OASIS inefficiencies, derates, administrative system limitations all contribute to market inefficiencies.
    - Transmission utilization is perceived differently, however, general concern with contract path method causing over-subscription. Also, Network is rarely constrained while the Interties are often curtailed; in fact, the Interties are curtailed in order to relieve Network congestion.

4. Existing Transmission Constraints
    - Congestion and curtailment issues raised by marketers and entities at the fringe.
    - BPA Network customers do not see congestion/curtailment as being a problem.
    - Congestion instances and costs are not systematically maintained due to the time constraints when the curtailments occur; due to the typical occurrence of pre-schedule curtailments; and this negatively impacts investment and other operational decisions (such as the value of redispatch).
    - Polices that cause curtailments to be implemented based upon capacity rights rather than actual schedules has had a significant impact.
    - Congestion is increasingly problematic and is indicated in the increasing number and frequency of curtailments.

5. Inconsistent Treatment of Generators/Loads
    - Market participants are not allowed to provide Ancillary Services simply due to limiting administrative systems.
    - There is a lack of transparency for pay-back of inadvertent energy.
    - The terms associated with Ancillary Services are not consistent among Transmission Providers.
    - RAS is required but not compensated at all or not compensated on a comparable, transparent basis.

- There are significant efficiencies to be gained as a result of better access to efficient ancillary services via operation of independent and robust markets.

6. Tariff and Business Practice Confusion
    - There are serious inadequacies in terms of the region having a common and comprehensive OASIS.
    - There are serious problems in terms of inconsistent Business Practices and interpretations of the OATT.
    - There are serious problems in terms of inadequate administrative systems, e.g., inability to clear long-term queues, inability to build accounts, inability to participate in various markets, etc.
    - There are serious differences in terms of tagging requirements and regimes.
    - The pro forma OATT was not designed to support intermittent resources.
    - There are increasing number and frequency of commercial and market disputes resulting from increasingly complex transactions, diverse commercial standards, increasing numbers of market participants, and lack of transparency of commercial and market data.

7. Planning and Expansion
    - A single, regional view of the transmission system will enable the most cost-effective solutions.
    - A single, independent planning function will best enable identification of solutions and get investments underway, funded, and both benefits and costs allocated.
    - A larger control area or regional view results in greater diversity in terms of generation and loads, which in turn, makes it easier and more cost-effective for operators to integrate remote, intermittent and new resources.
    - Current conditions cause an inability to perform needed system planning and expansion implementation.

Task Management Worksheet – detailed comments
Note: The respondent is masked (given a number, e.g., #15; and the alpha-numeric reference ties back to the survey questions).

1. Regulation Reserves
2. Contingency Reserves

3. Unused Transmission Capacity

- #1 See Path Utilization reports prepared by SSG-WI for details.
- #1 3.b. TBL has established a flow based system that now applies to long term and short term firm purchases of transmission and is being extended to the pre-schedule and real time periods. "It is possible that a flow based system could sell and manage transmission using the POR and POD to calculate the flow based impact on their system and ATC…" This could be expanded to other contiguous systems.
- #2 3. d. The BC-Alberta path rating and OTC is generally operated at a transfer level below its WECC defined path rating due to constraints imposed by the AESO. As a result, ratings may change significantly between pre-schedule and real-time causing real-time curtailments. This seams issue could benefit from broader coordination and determination of interconnection ratings.
- #3 ATC determinations are different; an independent entity coordinating ATC methodologies would be very helpful and result in greater efficiencies.
- #4 1.c. Under-utilization of transmission capacity is the result of the mismatch of capacity at common interfaces. This could be addressed by investment in phase shifters, adding lines, adding conductors, etc. The impact that we realize is not being able to import (as much as 50% of total capability or 500 MW; 200 MW is probably the common loss that we incur).
- #5 The application of TRM and CBM seems to differ from TP to TP.
- #6 TRMs appear to be excessively conservative amongst some providers and have caused discrepancies of ATC between two sides of a tie-line. Control Areas need to agree on TRM amounts and having Grid West should help resolve this problem.

4. New Transmission Construction including problems in Long-term Queue

- #7 7.f. Significant problems have been experienced with delayed system studies. Moreover, when TPs respond to long-term requests, counter-offers that do not seem to follow any particular logic are made which appear to be inconsistent application of the tariff.
- How much money has been spent on studies? How many duplicative studies have been done for individual flowgates?
- #2 6.f. Numerous examples of System Impact Studies and Facilities Studies not completed in a timely manner and where customers declined

service (cost of upgrade, more than 30 days needed to execute a Service Agreement; the market changed during the delayed study period, etc.)

- #6 6. f. Most transmission providers don't have the resources needed to complete System Impact Studies or Facilities studies in a timely manner which results in all or a portion of a transaction to be foregone. The current expected return time for a SIS from BPA is over a year; there are numerous request in the BPA long-term queue that are still in study but for service that should have started over 4 years ago.
- #8 1.a. There is not enough transmission capacity to enable purchasing the lowest cost generation; loads are capture to local generation.

5. New Generation Resource Construction and Location

- #5 1.e. Pancaked rates is the most difficult hurdle for wind project development.
- #9 Pancaking alone send price signals for locating resources and resources close to load are preferred as a result. This can result in inadequate resource diversity and inefficient dispatch.
- #13 The transmission function must be modified to accommodate renewable resources.
- #13 Current transmission service rates are problematic for low load-factor resources.

6. Pancaked Rates

- RRG Pricing Workgroup. The Pricing Workgroup has identified rate pancakes in the form of short-term and nonfirm transactions that have not been sheltered under long-term arrangements ($123 million). This amount is composed of four categories of transactions: (1) entities that are NWPP members but not members of the Grid West Major Transmission Utilities' (MTU) class ($11 million); (2) entities that are *not* NWPP members and are not members of the Grid West MTU class ($30 million); (3) affiliates of Grid West MTUs ($56 million); and, (4) transactions among Grid West MTUs ($26 million).
- Transactions involving multiple rates:

	$/KW/month	$/MW-hour
• Avista:	$1.40/kW/month	($1.89/MWh)
• BPA (2 segments)		
1. PTP-06:	$1.216/kW/month	($1.64/MWh)
2. IS-06:	$1.211/kW/month	($1.63/MWh)
• BCTC:	$3.60/kW/month ($US)	($4.86/MWh)
• Idaho Power:	$0.97/kW/month	($1.31/MWh)
• NorthWestern:	$3.10/kW/month	($4.19/MWh)
• PacifiCorp:	$2.025/kW/month	($2.74/MWh)
• PGE:	$0.52/kW/month	($0.71/MWh)
• Puget:	$0.32/kW/month	($0.31/MWh)
• Sierra/Pacific		

1. Zone A: $2.88/kW/month ($3.89/MWh)
2. Zone B: $1.40/kW/month ($1.89/MWh)

- #7 6.c. The lack of consistency in terms of calculating ATC among transmission providers is a problem when transactions involve more than one system.
- #7 6.d. There is little consistency among transmission providers in terms of how capacity is awarded, capacity is scheduled and interrupted. This is especially problematic in the hourly and day-ahead markets because markets aren't cleared on the same hours. Some providers still don't have a long-term OASIS.
- #6 1.a. Compare market hub prices and deduct wheeling, scheduling, other pancaked fees in order to measure the potential for improving market efficiency.
- #6 3.e. The lack of consistency among transmission providers in terms of OASIS, reservation procedures, scheduling, etc. directly impacts transactions when more than one leg of transmission is involved. Providers have different time limits for accepting and confirming transmission request, e.g., some allow a monthly firm request to be made many months out, others set a 60 day earliest window. When confirmation deadlines are short, there may not be enough time to have the connecting leg accepted.
- #6 Long-term capacity is not consistently determined, e.g., BPA releases more firm transmission at the BC/US border and on the Southern Intertie in comparison to BCTC and the CAISO. Some adjacent control areas do not coordinate TTC hourly in real-time. Grid West should bring about improvements, as the single scheduling entity and eliminating the need for multiple scheduling systems and related charges.
- #6 7. d. A single, independent entity could administer and manage a single queue for that merchants can arrange all necessary transmission at once.
- #8 1.b. Because of the complexities and transactional burdens of dealing with more than on e transmission system, we rarely source from supplies that are not available to the BPA grid.
- #5 1.e. Pancaked rates is maybe the most difficult hurdle for wind project development.
- #5 6.c. Even when ATC is available, it is extremely rare when a transaction can absorb more than one transmission charge (i.e., two or more pancakes usually kills the economics of any transaction).
- #3 1.e. Resources located within one's own control area begin with a built-in economic advantage over those that involve wheeling across systems.
- #9 7.b. There are problems and inefficiencies when transactions involve more than one transmission system. Besides the multiple charges, the processes do not lineup, capacity may not be available on both systems, the amount of time needed to do studies do not line up, etc.

- #4 1.a. Pancakes can result from a transaction crossing a system and one transformer.
- #4 1.e. The impact of rate pancakes and transmission congestion in general has caused us to add generation closer to load centers.
- #13 Multiple fixed cost charges impedes efficiency of the wholesale power market especially when multiple transmission providers are involved (not just multiple segments on one system).

7. Maintenance Outage Coordination: transmission and generation
- #7 2.a. There is a general lack of market concerns in the scheduling of outages. There is also a significant “seams” issue with California.
- #6 2.a. While BPA and others try to facilitate the market, it is very difficult to initiate discussions to minimize the impact of significant outages. Part of the problem is that the costs of transmission outages are not tracked and so the importance of minimizing outage days is often understated. An outage on the Northern Intertie in July 2003 resulted in 240,000 MWh in lost trade, when the intertie was derated from 3150 MW to 500 MW for 20 days. The financial impact included lost transmission revenue (nonfirm in BC and in the US), foregone use of firm transmission, lost power revenues and increased cost of replacement power.
- #6 2.a. The ATC determination 60 days out is different from the ATC determination when allocating short-term firm transmission capacity which results in problems when trying to securing capacity. There should be one method for calculating ATC for outages which would result if Grid West were in place.
- #6 3.d. The lack of coordination of ATC determinations between adjacent control areas is a serious problem, especially between the PNW and California. In addition, some providers still don’t post ATC on OASIS and others have inaccurate postings. This circumstance causes foregone transmission revenues or opportunity for using already purchased transmission capacity and higher energy costs because secondary supply sources have to be secured in order to fulfill transactional obligations.
- #10 1.e. Snohomish PUD’s resource plan indicates interest in wind generation (starting in 2009), however, two wheels make this resource option too costly.
- #10 1.f. Look at RFP responses for the purpose of determining the cost impact of pancaked rates on wind and geothermal resources.
- #12 5.d. The TTC determinations for the north and south ends of the AC Intertie are not coordinated and result in over-reductions of schedules.
- #11 3.b. We have experienced significant derates (185 MW of reduced capacity year-round) as a result of WECC’s OTC study which cost us about $7.5 million/year of lost opportunities. It is not clear if a regional transmission entity could have much impact on these studies, given that WECC is the regional reliability governing body.
- #4 3.d. Changes in ATC determinations are usually explained with one notable exception, the CAISO.

8. Market Monitoring

- #13 The region needs a market monitor established by an Independent Entity; the first defense against market problems.
- #13 A west-wide market monitoring entity could help to address seams (commercial and reliability) issues between California and other regions.
- #13 A market monitor should help reduce exposure to volatile and unfair prices and provide early identification of problems and recommended solutions.
- #13 An independent entity should promote higher transparency of market data by sharing information with applicable regulatory agencies and by recommending improvements to aid the efficient evolution of western markets.

9. Reliability

- #1 3.c. "Programs to control failure propagation, which we assume to be safety nets, could be enhanced by an organization that has wider geographic scope." Currently, these programs are done by individual utilities or through regional councils, power pools, etc. which take a long time. "If one entity were in control of larger portions of the regional grid, they would have better visibility of potential problems and access to more of the system to provide more equitable and effective safety nets." Remedial Action Schemes (RAS) can help, however, these schemes cause generators to temporarily lose their ability to control output of their projects.
- #6 3.b. Reliability polices should be changed to ensure that energy schedules are only cut on a reliability basis not, for example, as a result of accounting problems.
- #11 5.b. We have direct experience with non-comparable treatment of RAS; the region should pursue improvement in how RAS is used including comparable compensation for providing such.
- #13 The current structure of the grid is a collection of independently owned and operated transmission systems which have become interconnected for reasons including back-up, reserve sharing, reliability and accommodating economic wholesale power transactions. Recently, the volume of transmission transactions has increased dramatically because of open access, some deregulation, an increase in merchant plants, price volatility, etc. Over the last 10 years, the amount and complexity of transmission transactions has increase, while the transmission facilities and interconnections between systems have remained largely unchanged. The aging transmission facilities are expected to accommodate far more transactions today than they did a decade ago.
- #13 Reliability planning criteria address how one control area may affect another but do little to detail what reliability criteria individual control areas

must utilize internally. Moreover, compliance with WECC criteria is generally voluntary.

- #13 There is a lack of real-time coordination between control area operations which means that regional power requirements are unlikely to be provided either as quickly, reliability or as efficiently as could be.
- #13 The Pacific Northwest Security Coordinator was established to provide reliability coordination, but it has limited operational authority and plays a largely advisory role.
- #13 As evidenced by the blackout of August 2003, coordination of multiple control area operations without sufficient transparency and appropriate authority can be an ineffective approach to reliability.
- #13 In a region with 15 separate control areas, there is inefficiency simple due to the fact that during real-time operations each control area is largely on its own, essentially operating its own real-time market with its limited options, unable to utilize more efficient options that may exist on other control areas.

10. Independence from Market Participants

- #7 2.f. Discriminatory treatment occurs due to the lack of allowance for regional input, e.g., the recently adopted “Curtailment Calculator” which establishes flowgates and priorities for cutting generation.
- #7 5.c Discriminatory treatment in the AS market.
- #6 2.b. The barriers to entry into the AS market is a result of varied and different rules when it comes to technical requirements, e.g., minimum generator size limits for providing reserves, as well as inconsistent business practices and business systems which preclude broad market participation.
- #8 5.a. There is non-comparable treatment of the application of energy imbalance; BPA PBL is not subject to energy imbalance in serving full requirements customers’ NT loads; customers who self-supply AS are subject to energy imbalance charges.
- #12 2.b. A better understanding (which could be achieved through an independent entity) of locational requirements for operating reserves could lead to a regional reserves market that could lower overall costs.
- #5 Some Control Areas don’t allow non-utility generators to buy or self-provide spin and non-spin reserves.
- #5 In regions without RTO structures, non-utility generators subsidize host control areas with free or at non-market rates for VAR support, spin, non-spin and frequency response.
- #5 Inadvertent pay-back can be priced at marginal system prices for which there is no transparency.
- #5 Imbalance payments are charged regardless of whether there spill is occurring.
- #5 Some TPs have resisted paying independent generators for reactive support while at the same time paying its power business line for a very similar service.

- #10 5.c. Non-network resources should get the benefit of redispatch on the federal system.
- #12 6.b. RAS is often required but provision is not compensated.
- #13 While robust bilateral markets for energy have long existing, the limited markets for ancillary services – though growing – are less developed and are neither liquid nor well organized. Furthermore, these markets operate on a forward basis, with each party basing its pricing on what it believes the value to be rather than actual operating costs which can produce inefficient outcomes.

11. Service to Outlying Areas – addressed in sections 5. and 6.

12. Market Innovation
    - #10 Service that supports, rather than discourages, intermittent resources.
    - #12 6. There needs to be an effective way to clear the queue; a regional queue could be very helpful.
    - #11 2. Strategic placement of phase shifting transformers for throughout the western interconnection, paid for by the entire interconnection would help relieve constraints.
    - #11 2. A regional redispatch market could be used to effect the necessary transmission loading relief; this could be done by the Reliability Coordinator, if it had the proper tools, or by another entity with the authority to order redispatch.
    - #9 7.a. There may be opportunities to increase the use of existing facilities without degrading service to existing transmission users by designing additional transmission service products. By way of example, a transmission product for wind is a desired service.
    - #5 Cost estimates for OASIS inefficiencies, transmission line derates, missing RODS accounts and inconsistent tag approval process costs this company in the mid range of $500,000/year.

13. Energy Balancing

14. Planning/Expansion
    - #1 3.a. Reference to Transmission Adequacy Standards as being needed to evaluate transmission infrastructure needs for reliability, generation dispatch and curtailment procedure purposes.
    - #1 3.a. "The very occurrence of the 2001 Energy Crisis demonstrates that despite the RMS requirement to have adequate capacity to meet load and ensure the reliable operation of the transmission system, there is no long-term planning mechanism in place to ensure the short-term criterion is met without implementation of very drastic measures, e.g., buying down the aluminum load in the Northwest." A regional resource adequacy metric and target is needed.
    - #1 7.a. Because of the lack of a congestion management system, congestion cost information is not available. Insufficient capacity results in

cutting or denying schedules providing little information on cost implications. Costs are internalized but not measured. Transmission Providers have a rough idea of how often schedules are not accommodated but little else even though they are expected to make economic upgrades. New users are expected to fund expensive transmission with little information.

- #1 7.c. The lack of a formal process for resolving planning issues results in project delays (examples provided). Utilities often withhold investments in order to gain leverage in commercial issues.
- #1 7.d. A single planning forum with responsibility and authority is needed to ensure that planning is done in an open and coordinated manner; so that least cost plans are identified; and, to make sure that needed fixes are timely implemented. BPA has only 50% of the grid, when considering the NWPP.
- #2 7.c. If requests for new transmission service are substantive and involve many other entities in the western grid, planning coordination is fundamental in determining the least cost transmission path. An example of this coordination is the planning study to determine the transmission service requirements to transmit power from the Alberta tar sands to the US system.
- #6 7.a. The lack of information about the value or cost of congestion has impacted a number of transmission investment decisions, e.g., reluctance to engage in a regional technical discussion about the Puget Sound Area before January 2004 (before Seattle was instructed to cut over 1000 MW of schedules); and the Kangley – Echo Lake upgrade, which was held up due to issues surrounding the allocation of costs and benefits. The existence of an independent planning entity will help to move planning studies and decisions along.
- #6 7.b. The cost of delay could be estimated by reviewing the status of BPA's G20 projects, e.g., which have been completed and which have not.
- #6 7.c. Planning will be greatly improved with the establishment of a collegial, creative dialogue among regional participants focusing on common problems. Grid West could help to enable and encourage technical discussions and consensus development. Grid West could also help to move current planning discussions beyond high-level conclusions and toward real investment and upgrades.
- #8 7.b. When dealing with planning and expansion issues, "disagreements, delays, and inaction is the name of the game." We have had to implement less than optimal solutions because of the intransigence of other providers, or an unwillingness to allocate costs among transmission providers.
- #8 7.c. Coordinated planning is crucial; BPA will be facing tighter and tighter constraints on its borrowing authority so alternatives to the BPA-default solution will be necessary going-forward.

- #5 7.a. The lack of information regarding historical curtailments or expectation of curtailments makes resource development decisions and transmission investment decisions extremely difficult.
- #10 7.a. The cost of congestion has made investment in the McNary-John Day 500-kV upgrade uncertain.
- #10 7.b. The allocation of costs associated with investment, e.g., reliability vs. commercial expansion, needs to be done by an independent entity.
- #10 7. c. Coordinated planning by an independent, regional entity would be best positioned to identify “What transmission upgrades and expansion projects are most cost-effective for the region?”
- #10 7.d. Redispatch markets and mature secondary transmission markets would benefit renewable generators such as wind. Wind can only use about 30-35% of the capacity purchased under a Capacity Reservation-type rate which greatly affects the cost-effectiveness of the resource.
- #12 7.c. Planning efforts are hindered by multiple request queues among transmission providers and unclear guidelines on how to address impacts on third parties. A regional queue could reduce confusion by establishing priorities on positions in the queue.
- #12 7.d. The problem that plagues investment in transmission is funding; the G-20 project list would address most congestion issues in the region, however, no one wants to fund the investments.
- #11 7.a. The cost of load shedding has been estimated by this company and considered in the justification of investments, however, data regarding the cost of congestion is not available but would be helpful information to further inform a decision to invest in expansion.
- #11 7.b. The uncertainty about the cost and benefit allocation may delay investments in phase shifters that are needed for managing congestion. Another example is the lack of agreement about the allocation of transmission costs between existing and new generation and how these allocations are influenced by the generators’ respective interconnection and queue positions.
- #11 7.b. Coordinated planning could go a long way in terms of expediting regional planning efforts and could result in a better optimized transmission system.
- #9 7. a. Transmission limitations force utilities to stay close to load, even though there is little fuel diversity for resource choices close to load.
- #9 7.c. The NW Transmission Assessment Committee has improved regional planning, however, the challenge in getting planned transmission built and paid for remains.
- #13 At present, transmission planning is done on an individual control area basis, only with limited regional coordination; there is only ad hoc coordination on certain projects.
- #13 There are many examples of much-acknowledged reasons for lagging transmission infrastructure investment including inconsistently adopted and applied development criteria, unclear cost recovery mechanisms and unknown effects from parallel system operations. An Independent Entity

is needed to provide the appropriate forum for developing consistent and uniform criteria for infrastructure development and to ensure consistent application and implementation.

- #13 An Independent Entity with “Reliability Back-stop” authority would alleviate the concern about uncertain cost recovery for large transmission investments.
- #13 Regional planning is critical to a system that is using a flow-based methodology which involves multiple systems (currently 15 control areas).

15. Congestion Management

- 4.b. TBL curtailments (May – September 2003) – summary prepared – interview with BPA is scheduled.
- #1 2.e. West of Hatwai – problems with issuance of dispatch orders, however, the dispatch isn’t effective. Need for a broader view of the system to better understand the implication(s) of redispatch orders.
- 4.a. TBL currently has 18 paths posted.
- #1 4.c. Real-time curtailments occur when actual power flows exceed OTC. No consistent information in dispatch logs is kept, e.g., action taken, how much generation was affected, etc.
- 4.c. See BPA’s log of OTC violations (1/1/2004 – 12/03/2004):

COI:	24	generation redispatch; loop flow mitigation; counter-schedule; circulate on PDCI
MT-NW:	11	phase shifter operation; schedules cut
Canada-NW:	4	phase shifter operation; schedules cut
Columbia Injection:	3	Generation redispatch
North of Hanford:	2	Generation redispatch; schedules cut; series caps bypassed
I-5 Corridor:	2	Generation redispatch; schedules cut; series caps bypassed

- #7 1.d. Lack of knowledge about how schedules, currently determined by contract path, affect constraints. The Interties are cut in order to relieve Network constraints.
- #6 Firm purchases of capacity on the Pacific Intertie have been curtailed over 20% - much of which is the result of relieving constraints on the BPA Network.
- #7 4.c. There is a lack of consistency in terms of how ATC is determined which affects the service request process and degrades the quality of service.
- #7 5.b. The reliance on RAS and the lack of consistency in terms of how it is compensated poses problems.
- Can we identify the amount of RAS that is currently relied upon and get a log of how often the schemes are being armed?
- #3 3.c. RAS schemes, especially for coal plants can result in significant exposure to damage to systems (pumps, motors, automatic valves, etc.) in

the event of rapid plan shutdown. In addition, there is an immediate loss of energy sales due to plan tripping which affects the economics.

- #2 3.e. Transmission curtailments seem to be premature on the BPA system; curtailments are made before counter-schedules are taken into consideration.
- #6 1.b. The Northern Intertie is used as a tool for managing congestion on the BPA Network. PSANI discussions in 2004 demonstrated that generation on the Network, i.e., 1 MW at Seattle's Skagit facilities had significant leverage in terms of managing congestion as it was equivalent to 9 MW on BC generation. This is a solid example of why it is important to know which generators provide the most physical relief.
- #6 3.b. Parallel flows in the Puget Sound Area have significant affects on Northern Intertie transfer capability which results in restricting AESO's and BC Hydro's ability to deliver or receive Operating Reserves; increased risk of curtailments to Puget Sound entities and firm obligations, such as Canadian Entitlement; increased potential for lost transmission revenue or lost opportunity (firm, resale of service, nonfirm); and, increased volatility of energy prices.
- #6 7.a. What is most unfortunate is that congestion and its associated costs are not formally tracked. When we get preschedule curtailment notices we implement work-around processes and when we receive real-time curtailment notices, we scramble to ensure that load is not interrupted. We do not formally track the implications and costs of congestion because when the situations arise, we focus on fixing the problem, not documenting it. The frequency with which we have to deal with curtailment has grown to a level that concerns us.
- #8 4.b. See log (2002 – 2004) of curtailments.
- #10 1.b. Redispatch could be used to free-up transmission across congested paths, e.g., West of McNary, Paul-Alston, Alston-Keeler, I-5 corridor, Willamette Valley.
- #12 2.f. The time between curtailing a transaction and causing a change in flow is too long.
- #9 4.b. See curtailments on facilities operated by BPA: http://www.transmission.bpa.gov/orgs/opi/intertie/index.shtm.
- #9 5.b. We experience capacity de-ratings and pre-schedule limitations, however, we do not have a reporting mechanism to quantify all instances. The common causes for capacity derates include: pre-scheduled transmission line work; hydro conditions in Montana; derates on the COI due to loss of generation, e.g., CGS; forced generating unit outages; forced line outages; unscheduled flow procedures; incorrect assessment (necessary derate) by BPA.
- #4 1.b. We use phase shifters and schedules to balance flow on available paths in order to optimize the use of paths with reliability constraints and to reduce losses. Phase shifters could be used at times to reduce some constraints with appropriate compensation for increased losses and other incremental costs.

- #4 1.d. Constrained transmission results in using gas and oil-based generation instead of coal, hydro and purchased-power from independent generation.
- #4 2.e. We have experienced curtailments for congestion off of our system and have learned later that the curtailment did not address the flow problem.
- #3 5 There have been instances on both the BPA and Pac systems when curtailments have been ordered based upon erroneous transmission dispatcher instructions.
- #12 The TTC on the Pacific Intertie is not consistently determined and coordinated, resulting in over-curtailment of schedules. This results typically when CAISO implements curtailments in order to be in line with operating limts and then, BPA implements cuts, however, the cuts involve non-congruent schedules.
- Daily derates on BPA's system: http://www.transmission.bpa.gov/OASIS/BPA/outages/hourly/hourlylimits.shtml
- There are 20-30 paths around the west that "impact desired transactions".
- #5; #6Real-time curtailments on the Pacific Intertie have been too numerous to gather.

16. Dispute Resolution

- #7 5.d. Attempts to remedy problems through arbitration, litigation and negotiations are expensive and inefficient. Efficiencies could be gained through broader participation in issues.
- #6 6.a. We have serious concerns regarding transmission providers writing business practices that are not based on the intent of the tariff but are used to accommodate system flaws. Grid West should be a positive force to ensure that processing systems are written to support business practices and that business practices are written to support the tariff.
- #6 6.a. We have participated in a number of complaints against transmission providers regarding business practices and tariff issues (e.g., FERC Hotline, arbitration under NRTA, WRTA and/or WECC rules, to FERC mediation, to formal complaints to FERC). The quicker less formal approaches, while less costly, are less binding and do not serve a precedent among transmission providers (which can lead to the same dispute multiple times). The more costly are less timely and may help with establishing precedents however, they are less helpful in dealing with the immediate problem. One unfortunate consequence of conflict is when disputing parties are all awarded capacity which results in oversold capacity (which the transmission providers enjoy) with greater pro rata curtailments and no consequence to the transmission provider because no revenues are credited as a result of curtailments.
- #6 6.a. In addition to the cost of the dispute, when capacity involves multiple systems and some portion involves constraints, additional costs are incurred, e.g., through stranded investment for capacity rights,

additional transmission costs to find an alternate path, the cost of secondary, and more costly, suppliers.

- #11 Parallel flow issues (unscheduled flow from outside our control area) are a problem; these flows are difficult to control but could be addressed comprehensively by an entity that looks at the entire region.
- #11 Disputes persist as a result of shared paths for which a portion is scheduled up to system capability, when the entire path cannot accept such levels in total.
- #5 Serious concerns regarding lack of long-term OASIS, system inadequacies, etc.
- #5 Throughout the western interconnection, there is a lack of continuity in terms of what constitutes a proper NERC tag configuration.
- #3; #5; #6; #7; #10; #13 Different OATT interpretations:
    - shaped annual firm transmission;
    - extension of commencement of service;
    - redispatch (can/cannot be used to create transmission capacity);
    - ancillary services requirements (e.g., generation-supplied reactive); and,
    - losses requirements
    - generation imbalance penalty (for wind)
    - Tag before schedule policy
- #10 Significant long-term queue problems could be better solved by an independent entity like Grid West.